DOE Exhibit 1.0

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

COMMONWEALTH EDISON COMPANY	)	
	)	Docket No. 07-0566
Proposed general increase in electric rates	)	

DIRECT TESTIMONY

OF

DR. DALE E. SWAN

ON BEHALF OF

THE

UNITED STATES DEPARTMENT OF ENERGY

FEBRUARY 11, 2008

EXETER

ASSOCIATES, INC.
5565 Sterrett Place
Suite 310
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STATE OF ILLINOIS

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Q. PLEASE STATE YOUR NAME, OCCUPATION AND ADDRESS.

A. My name is Dale E. Swan. I am a senior economist and principal with Exeter Associates, Inc. Our offices are located at 5565 Sterrett Place, Columbia, Maryland 21044.

Q. DR. SWAN, PLEASE SUMMARIZE YOUR PROFESSIONAL QUALIFICATIONS.

A. I hold a B.S. degree in Business Administration from Ithaca College. I attended a master's program in economics at Tufts University, and I hold a Ph.D. in economics from the University of North Carolina at Chapel Hill. Prior to my consulting work, I served as Assistant and Associate Professor on the economics faculties of several colleges and universities. I also served as staff economist with the Federal Energy Administration and with the Arabian American Oil Company. For the last 30 years, I have consulted on matters primarily related to the electric utility industry, the last 26 years with Exeter. Much of my work over the last two decades has concentrated in the areas of long-term electric power supply planning and contract negotiations for large power users, and on electric utility cost allocation and rate design. For much of this period, I have directed Exeter's utility support services projects with the United States Department of Energy (DOE). As part of this work, I have been responsible for technical supervision of Exeter's participation in DOE interventions in numerous rate cases, for the financial and locational assessment of generation projects, and for the negotiation of technical aspects of power supply and facilities contracts.

A complete copy of my resume is provided as an attachment to my testimony.

Q. HAVE YOU TESTIFIED IN OTHER REGULATORY PROCEEDINGS?

A. Yes. I have testified on a variety of topics relating to electric utilities in 56 proceedings before federal and state regulatory commissions. A complete list of the cases in which I have testified is provided as part of my resume.

Q. DR. SWAN, WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been asked by the Department of Energy (DOE), on behalf of the Federal Executive Agencies (FEA), to address the class cost allocations that are proposed by Commonwealth Edison Company (ComEd or the Company), as well as the distribution facilities charges that are proposed for the several classes of non-residential Delivery Service customers under Rate RDS (Retail Delivery Service). In addition, I shall address the rate design implications of the Company's proposed new Rider SEA (Storm Expenses Adjustment). Finally, I shall address the Company's proposal to terminate Rider ACT credits.

Q. WHAT MAJOR FEA FACILITIES TAKE SERVICE FROM COMED?

A. Two large DOE science laboratories take delivery service from ComEd. Argonne National Laboratory (Argonne) has a peak load of around 41 MW and takes service at 138 kV. Fermi National Accelerator Laboratory (Fermi) has a peak demand of approximately 62 MW and takes service at 345 kV. The Great Lakes Naval Training Center has an annual peak demand in the neighborhood of 24 MW. It is served over two 138 kV lines to the site and through two 138 kV/34.5 kV transformers that are owned by the Company. All three FEA sites are served under Rate RDS (Retail Delivery Service) as part of the High Voltage Delivery Class, with loads in excess of 10,000 kW.

Q. DR. SWAN, DO YOU PROVIDE EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I have attached DOE Exhibits 1.1 and 1.2 to my testimony.

Q. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. DR. SWAN, PLEASE BRIEFLY SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. As a result of my evaluation of the Company's proposed cost allocation and rate design, I draw the following conclusions and make the following recommendations.

1. The Company's embedded cost of service study (ECOSS) is fundamentally flawed, provides results that lack internal logic, and should not be used as the basis upon which to determine class cost responsibilities and to set rates for non-residential classes.

2. Rates for non-residential classes should be adjusted by the overall jurisdictional percentage increase that is allowed by the Commission.

3. If the Commission decides to base rates on the Company's flawed ECOSS, then adjustments should be made to the costs of the two High Voltage classes to eliminate loads served at voltages below 69 kV, and the costs of the low voltage system that are allocated to these lower voltage loads.

4. The Commission should direct the Company to disaggregate costs at least between the primary and secondary system when conducting its next embedded cost of service study.

5. The Company's proposed Rider SEA - Storm Expenses Adjustment -- will result in an improper allocation of storm-related cost or credits. This is sufficient reason for the Commission to reject the rider. Consideration should be given to a reserve accounting mechanism to make the Company whole for storm damage expenses, which would avoid the rate design problems associated with Rider SEA.

6. The Company's proposal to require the involuntary termination of Rider ACT credits for customers who have received that credit for 30 years is based on faulty logic and is unfair to the affected customers. The Company's proposal should be restricted to a voluntary program.

THE COMPANY'S RATE DESIGN PROPOSAL FOR NON-RESIDENTIAL CLASSES

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED RATE CHANGES FOR NON-RESIDENTIAL DELIVERY SERVICE CUSTOMERS.

A. In response to the Commission's Order in Docket No. 05-0597, the Company designed rates for seven classes of non-residential delivery service customers, and it has retained these seven customer classes in this filing. The rates that are proposed by the Company, and presented by Mr. Alongi and Dr. Jones, are developed through a mechanistic translation of the embedded unit costs into rates for the various components of service. This mechanistic translation is presented in ComEd Exhibit 12.2.

Q. WHAT DO YOU MEAN BY A MECHANISTIC TRANSLATION OF UNIT COSTS INTO RATES?

A. Mr. Alongi and Dr. Jones calculate the unit cost of each particular component of service by taking the total allocated embedded cost from the Company's embedded cost of service study (ECOSS), presented by Mr. Heintz in ComEd Exhibit 13.1, and by dividing that total dollar amount by the billing units for the component of service in question to obtain the average unit cost of that service component, based on the ECOSS. For all intents and purposes, those unit costs for the Distribution Facilities Charge (DFC) were simply set as the DFC rates for the several classes of non-residential customers. Since the lion's share of these customers' delivery service revenues are recovered through the DFC, this amounts to rates that would recover almost exactly the cost of service that is allocated to each of these several customer classes by the Company's ECOSS. Thus, the reasonableness of the Company's proposed rates rests heavily on the reasonableness of the Company's ECOSS, and the appropriateness of using the Company's ECOSS to set rates in this proceeding.

Q. IS THIS THE SAME METHOD THAT THE COMPANY PROPOSED IN ITS LAST DELIVERY SERVICE CASE?

A. Yes. The Company proposed exactly the same mechanistic rate design in Docket No. 05-0597, except that the Company also attempted to consolidate the four largest non-residential classes into one. The Company's mechanistic rate design approach was rejected by the Commission as it applied to the non-residential classes, as was its proposal to consolidate the largest non-residential classes.

Q. DR. SWAN, WOULD YOU PLEASE SUMMARIZE THE MAJOR RATE CHANGES FOR THE SEVERAL NON-RESIDENTIAL CLASSES.

A. Yes. As I mentioned, the bulk of these customers' delivery services revenues are recovered through the Distribution Facilities Charge, which applies to the monthly peak demand. Table 1, below, provides a comparison of the current DFC for each non-residential class with the DFC that the Company proposes to place into effect at the end of this case. The last column shows the percentage changes in this charge that would result from adoption of the Company's proposal.

Table 1

Non-Residential Distribution Facilities Charges
($/kW-Month)

Delivery Class	Current	Proposed	% Change
Small Load (0-100 kW)	$4.29	$4.88	13.8%
Medium Load (101-400 kW)	5.01	5.70	13.8
Large Load (401-1,000 kW)	5.37	6.08	13.2
Very Large Load (1,000-10,000 kW)	5.22	5.76	10.3
Extra Large Load (>10,000 kW)	2.46	6.01	144.3
High Voltage (over 10,000 kW)	1.09	2.41	121.1
Other High Voltage	2.22	7.21	224.8

Source: Table 3, ComEd Ex. 12.0, p. 8.

Q. DO THESE PROPOSED CHANGES RESULT IN RATE SHOCK FOR CERTAIN LARGE NON-RESIDENTIAL CLASSES?

A. Yes. Keep in mind as a point of reference that the systemwide increase requested by the Company is 21.4 percent. With this system-wide increase as a point of reference, the proposed increases for the largest non-residential classes clearly are out of line and represent unreasonable increases. Specifically, the proposed percentage increases are 144 percent for the Extra Large Load class, 121 percent for the High Voltage class with loads in excess of 10 MW, and nearly 225 percent for the class of High Voltage customers with loads up to 10 MW. If account is taken of the Company's proposal to eliminate Rider ACT credits for certain customers, the effective percentage increases for customers owning their own transformers would rise to 153 percent, 140 percent, and 234 percent, respectively, for those same three classes of customers. I think there is little doubt that increases of this magnitude, especially as compared to the proposed 21.4 percent average system-wide increase, are properly viewed as rate shock. Increases of this magnitude certainly violate any reasonable standard of rate continuity or rate stability.

Q. DOES THE COMPANY RECOGNIZE THE UNREASONABLE RATE IMPACTS ON THIS GROUP OF CUSTOMERS THAT RESULT FROM ITS PROPOSED RATES?

A. Yes. Mr. Crumrine has indicated in his testimony that rate impact is a consideration in the design of rates in this case. He states that, "In setting the current non-residential distribution charges, the Commission expressly created specific interclass subsidies in ComEd's last rate Order in Docket No. 05-0597." (Lines 128-129) He goes on further to state that, while ComEd does not believe these subsidies should be maintained indefinitely, the Company is prepared to work with the affected parties during this proceeding to fashion some kind of a phase-in program that would, presumably, provide some near-term rate relief, but would gradually move these customers to what Mr. Crumrine believes are the cost-based rates that the Company has proposed in this proceeding.

Q. DO YOU CONCUR WITH MR. CRUMRINE'S CHARACTERIZATION THAT THE "COMMISSION EXPLICITLY CREATED INTERCLASS

SUBSIDIES" IN SETTING THE NON-RESIDENTIAL DISTRIBUTION CHARGES IN THE LAST CASE?

A. No. There is no language in the Orders in Docket 05-0597 that explicitly states that the Commission wished to establish any kind of interclass subsidy among non-residential classes. The concept of interclass subsidies is only meaningful with reference to the determination of the costs to serve the various customer classes. My reading of the Order in the last case is that the Commission did not accept the results of the Company's Embedded Cost of Service Study (ECOSS) as an appropriate basis for establishing the DFCs for the several non-residential customer classes. Mr. Crumrine apparently chooses to conclude that the Commission's decision to set rates that vary from the Company's ECOSS means that the Commission expressly chose to establish interclass subsidies. That interpretation is self-serving. Another and more reasonable interpretation is that the Commission did not have sufficient faith in the Company's ECOSS to use it as a basis for determining the DFCs for these several non-residential customer groups.

Q. DO YOU BELIEVE THAT IT WOULD BE REASONABLE TO FASHION A RATE MODERATION PLAN WHEREBY THE INCREASES PROPOSED BY THE COMPANY ARE PHASED IN FOR THE EXTRA LARGE LOAD CLASS AND THE TWO CLASSES OF HIGH VOLTAGE CUSTOMERS?

A. I would agree that, if the Commission were to adopt the Company's proposed rates for these three non-residential classes, then the correct approach would be to phase in the resulting rate increases in order to provide some degree of rate continuity and stability. However, I believe the correct decision for the Commission is to reject all of the Company's proposed non-residential DFCs because they are based on a cost study that yields illogical results and that may not be the basis for determining class costs in the future.

Q. WHY DO YOU SAY THAT THE COMPANY'S EMBEDDED COST OF SERVICE STUDY MAY NOT BE THE BASIS FOR DETERMINING CLASS COSTS IN THE FUTURE?

A. As I testified in Docket No. 05-0597, the Commission only turned to the use of an embedded cost study when it was faced with the task of unbundling rates to facilitate retail open access. Specifically, the Commission moved to the use of embedded costs for determining class revenues and rates in Docket No. 99-0117, ComEd's first delivery services case. Prior to that, the Commission had relied upon the use of marginal costs for approximately two decades. My understanding is that the Commission made this change because it was concerned that prices set on the basis of marginal costs would provide some kind of unfair advantage to ComEd in the provision of competitive services during the transition to competition, and thereby retard the development of a competitive market.

The Company also has repeatedly endorsed the use of marginal costs as the proper basis for the determination of class cost responsibilities and the design of rates. Mr. Crumrine has testified, once again in this case, that:

> "...while ComEd continues to support marginal cost principles for the pricing of electric delivery services, in the interest of narrowing the issues in this case, ComEd is proposing the use of an embedded cost study for both interclass revenue allocation and rate design purposes. However, ComEd reserves the right to propose the use of a marginal cost study in future proceedings." (ComEd Ex. 11.0, lines 152-157)

Finally, in its Order in 05-0597, the Commission invited parties to address in ComEd's next delivery services case, whether marginal cost of distribution service has a place in setting electric distribution rates. (Order, Docket 05-0597, July 26, 2006, p. 160)

For all of these reasons, I think there is a distinct possibility that, when the transition to a competitive market is complete, the Company itself may decide to propose rates that are based on marginal costs. While it would be difficult to develop a marginal cost study on its own, another party may also take that step. Further, the Commission may believe that it is appropriate to return to the use of marginal costs to better provide price signals that reflect the value of conservation and insults to the environment. Therefore, it seems inappropriate to slavishly and mechanistically design rates that are no more than translations of unit embedded costs, especially if the resulting rates result in the kind of rate shocks that are being proposed by the Company for the Very Large Load class and the two classes of High Voltage customers. Once those rates are implemented, there could be further drastic changes in rates for these same customers, if the Commission were to decide to return to the use of marginal costs. That process is hardly consistent with the concept of rate continuity, which was one of the major ratemaking goals set forth by the venerable Professor Bonbright in his classic treatise on designing public utility rates.[1]

AN OVERVIEW OF THE COMPANY'S EMBEDDED COST OF SERVICE STUDY

Q. IS THERE A GENERAL TEST THAT YOU BELIEVE A COST OF SERVICE STUDY SHOULD MEET IF IT IS TO BE RELIED UPON TO SET CLASS REVENUES AND TO DESIGN RATES?

A. Yes. I think it is a generally held view among regulators, as well as among those that practice the "art" of rate design, that no one cost study provides the absolute correct

[1] James C. Bonbright, Principles of Public Utility Rates, Columbia University Press, New York, 1961, p. 291.

final allocation of costs among the various classes of customers or the absolutely correct unit costs of the various types of service that are provided. There are simply too many a priori ways to classify, functionalize and allocate costs. It is because of this lack of absolute certainty about the correctness of any one method, that a reliable cost of service study should at least produce results that are internally consistent and logical, and that comport with fundamental relationships among the costs of serving customers with differing characteristics, such as size and voltage delivery levels. Regardless of the specific numbers that are generated by a cost of service study, this general test needs to be met in order for the regulatory authority to have confidence that the rates it sets, based on that study, will be fair and equitable.

Q. WHAT IS THE GENERALLY HELD VIEW REGARDING THE RELATIONSHIP BETWEEN THE COST OF DELIVERY SERVICE AND THE SIZE OF A CUSTOMER'S LOAD OR THE VOLTAGE DELIVERY LEVEL?

A. It has long been generally acknowledged that the unit cost of delivery service is lower for large customers as compared to smaller customers; and that the unit cost of delivery service is lower for high voltage as opposed to lower voltage customers. Delivery costs per kW are generally lower for larger customers for several reasons. The most important of those is that, in the large category of non-high voltage service, customers may be served at a number of varying voltage levels. ComEd defines High Voltage Delivery Service as at or above 69 kV. That leaves a lot of different voltage delivery levels that are classified as "Low Voltage" or "Standard" delivery service. A standard voltage customer with a load between 1,000 kW and 10,000 kW is likely to be served at 12.5kV or 34.5kV. A standard voltage customer with a load between 0 kW and 100 kW is most likely to be taking service off the secondary voltage system -- at voltages less than 2,300 volts, according to the Company's response to COC 3.099. That means that the unit cost of serving a, say, 5,000 kW customer served at 34.5 kV should include only the cost of the 34.5 kV and higher voltage equipment, whereas the cost of serving a 10 kW customer served at secondary voltage includes the cost of the entire delivery system, from secondary voltage lines and transformers, through the primary system and the sub-transmission system. In short, the cost must be higher per kW for a secondary customer than a customer served off the 34.5 kV system. Of course, the same relationship holds when comparing customers served off what is defined as the high voltage system as opposed to what is defined as the standard voltage system. In the case of ComEd, customers served at 69 kV or higher voltages must have lower costs per kW than customers of similar size served at standard voltages.

Q. DOES THE COMPANY AGREE WITH THIS RELATIONSHIP BETWEEN SIZE AND VOLTAGE DELIVERY LEVEL?

A. It would seem so. Paul Crumrine testified as follows in Docket No. 99-0117:

> "There is a high degree of correlation between the size of the customer and the voltage level at which that customer takes service. In general the larger the customer, the higher the voltage level at which the customer is served." (ComEd Ex. 33.0, p. 4, lines 86-99, ICC Docket No. 99-0117.)

Q. DOES THE COMPANY'S ECOSS PRODUCE INTERNALLY LOGICAL RESULTS REGARDING THE COST OF PROVIDING DISTRIBUTION DELIVERY SERVICE TO THE SEVERAL CLASSES OF NON-RESIDENTIAL CUSTOMERS?

A. No. This can be seen by reviewing Table 2. In the Company's ECOSS, the unit cost of service among all the standard voltage non-residential customer classes is lowest for the class of customers with loads up to 100 kW – $4.88 per kW-month. Then the unit cost per kW rises to $5.70 per kW-month for customers between 101 kW and 400 kW, and to $6.08 per kW-month for customers in the 401 kW to 1,000 kW class. The cost falls somewhat to $5.75 per kW for the 1,001 kW to 10,000 kW class, then rises again to $6.00/kW for the largest standard voltage class with loads in excess of 10,000 kW. It is important to note that the unit cost for standard service for customers above 10,000 kW, as calculated by the Company's ECOSS, is higher than the unit cost for customers with loads from 0 kW to 100 kW by $1.12 per kW, or 23 percent, and higher than the unit cost calculated for customers with loads between 101 kW and 400 kW by $0.30/kW, or 5 percent. The calculated unit costs for these groups of customers are inconsistent with the generally held view that unit costs of delivery service should decline as the customer load increases.

Table 2

Non-Residential
Distribution Facilities Unit Cost
($/kW-month)

	$
Small Load Delivery Class	
0-100 kW	$4.88
Medium Load Delivery Class	
101-400 kW	5.70
Large Load Delivery Class	
401-1,000 kW	6.08
Very Large Load Delivery Class	
1,001-10,000 kW	5.75
Extra Large Load Delivery Class	
>10,000 kW	6.00
High Voltage Delivery Class	
>10,000 kW	2.37
High Voltage Delivery Class	
<10,001 kW	7.21

Source: ComEd Ex. 12.2, p. 2 of 3.

Q. IS IT POSSIBLE THAT GREATER DIVERSITY AMONG THE CUSTOMERS IN SMALLER SIZE CATEGORIES COULD LEAD TO LOWER AVERAGE UNIT COSTS FOR THOSE SMALLER SIZE CATEGORIES?

A. It is possible that there could be greater diversity among customers in smaller as opposed to larger size categories. Other things constant, that greater relative diversity will reduce the average unit cost per kW relative to other classes. However, it is highly unlikely that greater diversity among the smallest size categories (e.g., 0 kW to

100 kW) would overcome the greater cost of having to pay for all of the distribution system, whereas larger customers only impose costs on the higher voltage potions of the system. Thus, I do not believe that greater relative diversity among smaller size categories can explain the counterintuitive results obtained in the Company's ECOSS.

Q. WHAT ABOUT THE RELATIONSHIP BETWEEN THE CALCULATED UNIT COST OF SERVICE FOR STANDARD VOLTAGE AS COMPARED TO HIGH VOLTAGE CUSTOMERS? IS THAT RELATIONSHIP LOGICAL IN THE COMPANY'S STUDY?

A. Only partly. The unit cost as calculated in the Company's ECOSS for the High Voltage Delivery Class with loads in excess of 10,000 kW is lower than the unit cost as calculated for the Extra Large Load Delivery class, which has customers with loads in excess of 10,000 kW that are served at standard voltages. And the unit cost for these largest, high-voltage customers is the lowest of all the non-residential classes. That makes sense. However, the unit cost as calculated in the Company's ECOSS for High Voltage Delivery Class customers with loads up to 10,000 kW is the highest of all the non-residential classes – $7.21 per kW-month. Based on the Company's response to DOE 1-65, 30 of the 41 customers in this class have loads in excess of 1,000 kW. One customer is in the 0 kW to 100 kW group, four are in the 101 kW to 400 kW group, and six have loads between 401 kW and 1,000 kW. Thus, the cost per kW for high voltage customers with loads of up to 10,000 kW is significantly higher than for all comparably sized customers taking service at standard voltages. Importantly, note that the unit cost as calculated for this group of high voltage customers is $2.33 or 48 percent higher than the unit cost estimated by the Company's ECOSS for standard service customers with loads from 0 kW to 100 kW. This result makes no sense whatsoever.

Q. WHAT IS THE IMPLICATION OF THIS LACK OF INTERNAL LOGIC IN THE COMPANY'S ECOSS?

A. In my view, this lack of internal logic in the results of ComEd's ECOSS makes the study unreliable as a basis upon which to determine class revenue responsibilities or to design rates. The Company proposes to slavishly and mechanistically translate these estimated unit costs into Distribution Facilities Charges for the non-residential classes of customers. I believe the Commission can have very little faith that the rates to result from such a mechanistic translation of ECOSS unit costs will be fair and reasonable.

<u>THE COMPANY'S FAILURE TO DISAGGREGATE BY VOLTAGE</u>

Q. IS THERE A FUNDAMENTAL FLAW IN THE COMPANY'S ECOSS THAT LEADS TO THE KIND OF INTERNALLY INCONSISTENT RESULTS THAT YOU HAVE DESCRIBED?

A. Yes. The fundamental flaw in the Company's ECOSS is its failure to disaggregate customers and costs by voltage delivery level below the 69 kV line of demarcation for High Voltage Customers. The Company's ECOSS essentially places all delivery service costs below 69 kV into one bucket. That means that all customers that are served below 69 kV get a share of nearly all of the costs of the entire system below 69 kV, regardless of the voltage at which they take service. Thus, a customer that is served at 34.5 kV not only pays for its share of the distribution delivery system from 34.5 kV and up, but for most of the distribution system all the way down through the secondary system.

Q. WHY IS THIS A FUNDAMENTAL FLAW IN THE COMPANY'S STUDY?

A. As I stated earlier, large customers generally take service at higher voltage levels. As I also noted earlier, the Company agrees with this observation. We asked the Company (DOE 1-66 and DOE 4-03) to provide the voltages at which the several classes of non-residential customers take service, but ComEd asserted that it was unable to do so. However, it is reasonable to assume that many, and perhaps most, large, standard voltage, non-residential customers on the ComEd system take service at either 12.5kV or 34.5 kV. This is confirmed by the Company's response to IIEC 1.08, Attachment 1. In this response the Company provided a November 13, 2007 Loss Study ("2006 ComEd Distribution System Loss Factors"). Appendix C to that study shows that 100 percent of the load of High Voltage customers was served through High Voltage ESS and none of the load of these customers was served through any other element of the distribution system. It also shows that all of the loads of standard voltage customers above 1,000 kW were served through 34 kV elements or 12 kV elements, and that no part of their loads were served by any elements on the system below 12 kV. By failing to disaggregate any voltages below 69 kV, the Company's study lumps the costs of the entire system below 69 kV into one bucket, and allocates those costs among all customers served at any voltage up to 69 kV. That means that a customer served at 34.5 kV receives a portion of the costs of the entire standard voltage system, including the secondary voltage system, which that customer doesn't use.

This fact is confirmed by the Company's response to COC 3.099. That data response states that secondary distribution lines include "all lines and associated equipment operating at voltages less than 2,300 volts." The response goes on to state that the investments in secondary lines and associated equipment include poles, towers and fixtures, overhead conductors and devices, underground conduit and underground conductors and devices. Importantly, these all wind up in subfunction "Distribution Lines," which gets allocated to classes on the basis of non-coincident class peaks below 69 kV. That means, as the Company's data response states, that "Customers with load above 10 MW are allocated secondary distribution," even though the Company's loss study clearly shows that these customers do not use that portion of the system.

Q. SINCE THERE IS A VOLTAGE LINE OF DEMARCATION FOR HIGH VOLTAGE CUSTOMERS, ARE THE HIGH VOLTAGE CUSTOMERS PROTECTED AGAINST RECEIVING AN ALLOCATION OF THE LOWER VOLTAGE DISTRIBUTION SYSTEM COSTS?

A. No. Incredible as it may seem, designated High Voltage customers also receive an allocation of a significant part of low voltage system costs, including the secondary system.

Q. HOW DOES THIS HAPPEN?

A. There are a number of High Voltage customers, both in the class up to 10,000 kW and in the class of customers above 10,000 kW, that also have loads that are fed by Company lines entering the customer's premises at voltages below 69 kV. Fermi National Accelerator Laboratory is one of these customers. Apparently for ease of billing, these standard voltage loads are metered conjunctively with the customer's High Voltage loads and billed at the customer's High Voltage rate. In the ECOSS, these low voltage loads are included in the allocation of the lower voltage distribution system on the basis of loads below 69 kV. Thus the High Voltage classes receive an allocation of the lower voltage distribution system, including a portion of the secondary system.

Q. IF MANY OF THE HIGH VOLTAGE CUSTOMERS ALSO RECEIVE SERVICE AT VOLTAGES BELOW 69 KV, IS THIS A PROBLEM?

A. Yes. The Company's decision to combine in a single rate class, loads served at voltages below and at or above 69 kV introduces a significant intra-class cross subsidy. The cost of serving loads below 69 kV is understated, while the cost of serving loads at or above 69 kV is overstated under the Company's procedure. This results from the allocation of the costs associated with three categories of distribution facilities: (1) High Voltage Distribution Substations; (2) Distribution Substations; and (3) Distribution Lines. Consider, for example, the allocation of Distribution Lines to the High Voltage Delivery Class with loads above 10,000 kW. Under ComEd's cost of service allocation process, these costs are allocated to the High Voltage Above 10,000 kW class on the basis of NCP demands below 69 kV. Thus, even though customers receiving service only at 69 kV or higher bear no cost responsibility for any share of Distribution Lines costs, the inclusion in the High Voltage classes of loads served at voltages lower than 69 kV requires that all members of the class assume the cost responsibility for Distribution Lines costs.

Q. DO THESE INAPPROPRIATE COSTS CONSTITUTE A SIGNIFICANT SHARE OF THE TOTAL COST OF SERVICE ALLOCATED TO THE TWO HIGH VOLTAGE CLASSES?

A. Yes. This can be seen by reviewing the results on Schedule 2a, page 12 of the Company's revised ECOSS, provided in response to IIEC 1.02 Supp_Attach1.XLS. This schedule shows that, of the total cost of service of $5,016,676 for the class of High Voltage customers up to 10,000 kW, $2,367,285, or over 47 percent, is accounted for by the costs of High Voltage Distribution Substations, Distribution Substations and Distribution Lines, which are facilities that are not used to serve the legitimate high voltage loads in this class -- that is, loads that are served by lines entering the customer's premises at voltages at or above 69 kV. For the class of High Voltage customers with loads in excess of 10,000 kW, these costs account for $3,119,814, or nearly 19 percent of the total cost of service of $16,818,925 allocated by the Company's ECOSS to this group of customers.

Q. IF THESE COSTS ARE ALLOCATED TO HIGH VOLTAGE CUSTOMERS THAT ALSO TAKE SERVICE AT LOWER VOLTAGE LEVELS, THEN WHY DOES THIS RESULT IN AN INTRA-CLASS SUBSIDY?

A. The reason is that there is only one rate for both legitimate high voltage loads and loads served at lower, standard voltages. In response to IIEC 4.01, the Company states that, "ECOSS allocates the costs [of Distribution Lines and Substations] ... based only on NCP Below 69 kV...and does not allocate these costs to loads served at voltages entering customers' premises at voltages that are 'at 69 kV' or 'Above 69 kV'." In fact, because there is only one DFC for all the loads in this class, legitimate loads at or above 69 kV are required to pay for 95 percent of these costs in the Above 10,000 kW High Voltage class because those loads account for 95 percent of the billing demands of that class. (Company Response to DOE 1.17, Attach 1). In the class of High Voltage customers with loads up to 10,000 kW, legitimate high voltage loads at or above 69 kV are required to pay for 85 percent of these low voltage costs because these legitimate high voltage loads account for 85 percent of the billing demands of this class. Thus, high voltage loads that use none of the system below 69 kV are being required to pay for the costs of the low voltage system, including portions of the secondary system.

Q. BUT IF HIGH VOLTAGE CUSTOMERS ALSO HAVE LOW VOLTAGE LOADS, HOW DOES THIS RESULT IN AN INTRA-CLASS SUBSIDY?

A. It would not if all high voltage customers also received standard voltage service in the same proportion. But that is not the case. For example, two of the FEA facilities, Argonne National Laboratory and Great Lakes Naval Training Station, have no standard voltage loads. All of their service is delivered over lines entering their premises at or above 69 kV. Yet, they are required to pay a rate that includes the costs of the standard voltage distribution system, all the way down to significant portions of the secondary system. In general, customers in the two High Voltage classes that take a less than average proportion of their service at standard voltages will be subsidizing those who take more than the average proportion of service at lower voltages.

Q. DID YOU ADDRESS THIS SAME ISSUE IN THE PREVIOUS DISTRIBUTION SERVICES CASE NO. 05-0597?

A. Yes.

Q. HOW DID THE COMMISSION RULE ON THIS ISSUE?

A. In its July 26, 2006 Order, the Commission noted that the Company proposed a High Voltage Delivery Class "to take account of the fact that high voltage customers do not utilize a significant portion of ComEd's overall distribution system (p.199)." It went on to conclude that, "However, the Commission cannot understand how this logic can be extended to the portion of customers' service provided at standard voltage. Thus, ComEd's proposal to extend the high voltage discount to service provided at standard voltage is rejected." During the rehearing phase of the proceeding, ComEd proposed that the Commission reverse itself on this issue in order to facilitate implementation for January 2, 2007, and the Commission accepted the Company's proposal solely and specifically for that reason (Order on Rehearing, December 20, 2006, pp. 65-66.) Thus, despite the Commission's clear rejection of this approach in the last delivery services case, the Company again has combined the standard voltage and high voltage loads of designated High Voltage Delivery customers for purposes of allocating costs and recovering revenues. With adequate time to prepare for this split, unlike the limited time between the Order on Rehearing and the proposed date of implementation in the last case, one would think that the Company would have responded to the Commission's concern that it registered in its July 26, 2006 Order.

Q. HAVE YOU ANALYZED WHAT ADJUSTMENTS ARE REQUIRED TO THE COMPANY'S ECOSS TO SEPARATE THE COSTS THAT SHOULD BE ALLOCATED TO THE STANDARD VOLTAGE AND HIGH VOLTAGE LOADS OF THE TWO HIGH VOLTAGE CLASSES GIVEN THE OTHER ASSUMPTIONS UNDERLYING THE COMPANY'S STUDY?

A. Yes. The results of this evaluation are presented in DOE Exhibits 1.1 and 2.2, for the High Voltage Delivery Class Above 10 MW, and for the High Voltage Delivery Class Up to 10 MW, respectively. Essentially, the loads of the two High Voltage classes were separated into loads at or above 69 kV and below 69 kV, and these two groups are treated as separate customer classes. Then, with one exception, the demand-related costs that ComEd allocated to the entire class were allocated between these two sub-classes. The allocators used to make this separation are provided in the second page of each exhibit.

Q. PLEASE EXPLAIN THE DETAILS OF THE COMPUTATIONS UNDERLYING THE RESULTS IN DOE EXHIBITS 1.1 AND 1.2.

A. The analysis in DOE Exhibits 1.1 and 1.2 is relatively straightforward. Each item in the Company's derivation of distribution costs in Mr. Heintz' ECOSS, which is proposed to be recovered in the DFC, is allocated between loads served at voltages at or above 69 kV and loads served at voltages below 69 kV. The exception is that the Company incorrectly allocated High Voltage Distribution Substations to loads served at 69 kV, and that error is corrected in DOE Exhibits 1.1 and 1.2**.** The costs of High Voltage ESS were assigned directly to the groups of high voltage loads based specifically on the Company's response to DOE 3-3 and more generally on the responses to several other data requests. The costs associated with High Voltage Distribution Substations, Distribution Substations and Distribution Lines were assigned directly to the "low voltage" subclass, since none of these costs are the responsibility of customers at or above 69 kV. High Voltage Distribution Lines are used to serve both groups of customers and so were allocated based on each group's coincident peaks, which is the same allocator used by the Company. The only other significant cost item to be recovered through the DFC is the Illinois Electricity Distribution Tax, which the Company assigned on the basis of energy use. This cost element was allocated between the two subgroups using the same allocator. The remaining cost item is the Revenue-Related (Distribution) credit, which was assigned in its entirety to the low voltage loads in order to develop a conservative estimate of the differences in costs.

Q. WHAT ARE THE RESULTING UNIT COSTS FOR LEGITIMATE HIGH VOLTAGE LOADS UNDER YOUR ADJUSTMENT TO THE COMPANY'S ECOSS?

A. The unit demand-related cost is $1.97/kW-month for customers with loads above 10,000 kW, and $3.95/kW-month for customers with loads up to and including 10,000 kW.

Q. HOW DO THESE UNIT COSTS COMPARE TO THE UNIT COSTS OF THE OTHER NON-RESIDENTIAL CLASSES THAT YOU PRESENTED IN TABLE 2?

A. The resulting unit costs of the legitimate high voltage loads make more sense when compared to the Company's estimated unit costs of the other non-residential classes, which I presented in Table 2. In particular, the unit cost of high voltage loads up to 10,000 kW is now the second lowest unit cost of all the non-residential customers. Further, it is lower than the cost of providing standard voltage service for all of the other standard service classes. That means that the cost of serving a high voltage customer is lower than the cost of providing delivery service to a standard voltage customer of similar size. That makes sense.

Q. DO THE UNIT COSTS FOR THE STANDARD VOLTAGE LOADS OF CUSTOMERS IN THE HIGH VOLTAGE CLASSES MAKE SENSE?

A. No. Those unit costs are $9.59/kW-month for high voltage customers above 10,000 kW and a whopping $24.49/kW-month for high voltage customers up to 10,000 kW. This implies that the cost of serving these low voltage loads of high voltage customers ranges from 1.6 times to 5.0 times the unit costs of serving the same loads of standard voltage customers in the other non-residential customer classes. This makes no sense at all.

Q. DO YOU RECOMMEND THAT THESE ADJUSTED UNIT COST ESTIMATES BE USED TO SET DFC'S FOR THE TWO CLASSES OF HIGH VOLTAGE CUSTOMERS?

A. That is not my first recommendation. I firmly believe that the Company's ECOSS is fundamentally flawed by the Company's failure to properly account for the cost differences related to service at different voltage levels. In view of the infirmities of the Company's ECOSS, my first recommendation is that the non-residential Distribution Facilities Charges be adjusted by the average system-wide percentage increase that is allowed by the Commission in this case.

If, despite its infirmities, the Commission decides to use the Company's ECOSS as a basis to set rates in this proceeding, then I recommend that the legitimate high voltage loads of customers in the two High Voltage Delivery classes be determined using the adjusted unit costs that are provided in DOE Exhibits 1.1 and 1.2.

Q. HOW DO YOU RECOMMEND THAT THE LOW VOLTAGE LOADS OF HIGH VOLTAGE CUSTOMERS BE HANDLED?

A. There are two possible ways to treat these loads. The first is to use the low voltage unit costs presented in DOE Exhibits 1.1 and 1.2 as the basis for rates for these loads. However, as I just discussed, I believe these costs make little sense and so I recommend against this approach. The sensible way to handle these loads is to include them in the appropriate non-residential customer class. For example, the Fermi Laboratory has low voltage loads that run between 700 and 1,100 kW over the course of a year. It would be appropriate in my view to bill those loads at the rate that the Commission approves for the Very Large Load class, with loads from 1,000 to 10,000 kW.

Q. WILL IT BE POSSIBLE FOR COMED TO SEPARATELY BILL THESE LOW VOLTAGE LOADS FOR HIGH VOLTAGE CUSTOMERS?

A. Yes. First of all, the Company obviously separately meters these loads because the Company was able to provide us with the billing demands and the energy for the loads of High Voltage customers served at standard voltages in response to DOE 1-17. Further, the Fermi standard voltage load is already treated separately by the Company in its billing process since it does not provide the Rider ZSS-7 credit for loads served at less than 345 kV. Finally, based on the Company's responses to DOE 1-16 and 1-17, there are only 38 high voltage customers that receive some service at standard voltages. I would think that revising the billing algorithm for this relatively small number of customers would not pose a significant problem.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING HOW THE COMPANY SHOULD REVISE ITS ECOSS TO PROPERLY ACCOUNT FOR VOLTAGE LEVEL DIFFERENCES?

A. Establishing customer classes and determining the degree of disaggregation of costs always involves a trade-off between administrative burdens and the benefits associated with more accurately determining class cost responsibilities. In my judgment, and given the general configuration of the ComEd distribution system as I understand it, I think it would be appropriate to require the Company to break down the distribution system below 69 kV into two and possibly three voltage delivery levels – at or above 12.5 kV but below 69 kV; between 2,300 volts and 12.5 kV; and below the 2,300 volts that ComEd uses to define the line of demarcation between the secondary and primary distribution system. At the very least, I urge the Commission to direct the Company to break up the system into the secondary system and everything above secondary but below 69 kV in the preparation of its next ECOSS.

<u>Rider SEA – Storm Expenses Adjustment</u>

Q. PLEASE SUMMARIZE YOUR UNDERSTANDING OF THE COMPANY'S PROPOSED RIDER SEA.

A. Rider SEA is a tracking mechanism that will allow the Company to recover from or return to ratepayers the difference between baseline storm-related O&M expenses hardwired in base rates and actual storm restoration expenses incurred in the previous calendar year.

Q. ARE THERE RATE DESIGN IMPLICATIONS OF THE COMPANY'S PROPOSED RIDER SEA?

A. Yes. The Company proposes to recover all positive sums or to return all negative sums in Rider SEA through a per kWh charge or credit. This would treat the Company's largest customers, say high voltage customers with loads of greater than 10,000 kW, the same as a small residential customer, which is inappropriate. The Company has noted that, "The accounts (according to the Uniform System of Accounts) containing storm costs potentially includable in recovery through Rider SEA would typically be 593 (Maintenance of Overhead Lines), 926 (Employee Pension and Benefits) and 408.1 (Taxes other than income taxes, utility operating income)." An examination of the Company's ECOSS, ComEd Ex. 13.1, shows how those expenses would ordinarily be allocated to the various classes that use the parts of the system that ordinarily require the bulk of storm restoration efforts. Let me focus on the two high voltage classes because the picture is clearest for these two classes. Those two classes would be allocated approximately from 0.12 percent to 0.52 percent of Account 593 expenses, from 0.43 percent to 0.59 percent of Account 926 expenses, and from 0.42 percent to 0.61 percent of Account 408.1 expenses. These ranges reflect the difference between pulling low voltage loads out of the High

Voltage classes or leaving them in as the Company does. These same two classes are responsible for 5.1 percent of system energy. Thus, the customers in these two classes would receive charges or credits under Rider SEA approximately 10 times the costs that would be allocated to them under the Company's own cost of service study.

Q. DO OTHER LARGE NON-RESIDENTIAL CLASSES ALSO WIND UP RECEIVING CHARGES OR CREDITS IN EXCESS OF THE COSTS THAT WOULD BE ALLOCATED TO THEM UNDER THE COMPANY'S COST OF SERVICE STUDY?

A. Yes. The results would not be quite as pronounced, in particular because the Company incorrectly allocates portions of the lower voltage delivery system to these other large standard voltage customers. But, the effect is the same. Storm restoration costs are largely focused on the secondary and, to a lesser extent, on the primary system. Thus, the lion's share of these costs or credits should be allocated to those classes that use lower voltage distribution lines and line transformers. To allocate these costs or credits on energy use is incorrect and inequitable.

Q. IS THERE AN ALTERNATIVE METHOD BY WHICH TO MAKE THE COMPANY WHOLE FOR UNEXPECTED STORM DAMAGE EXPENSES?

A. Yes. It is my understanding that a number of other utilities use a reserve accounting mechanism to recover storm damage expenses on a dollar-for-dollar basis.

Q. WOULD THIS RESERVE ACCOUNTING METHOD SOLVE THE RATE DESIGN PROBLEMS?

A. Yes. I understand that under a reserve accounting mechanism the Commission would authorize the establishment of a storm damage reserve account into which storm expenses would be recorded. The accruals to the reserve are usually charged to

Account 924, Property Insurance. Based on the Company's ECOSS, I estimate that the two High Voltage classes would receive between 0.5 percent and 0.76 percent of costs in Account 924. While this is a somewhat larger share than the share of these expenses currently allocated to these two classes through the Company's embedded cost of service study (around 0.5 percent), the share is clearly much closer than the share of these classes' energy use (over 5.0 percent). In short, if a reserve accounting mechanism were established, the rate design problem largely goes away.

RIDER ACT

Q. PLEASE DESCRIBE THE EXISTING RIDER ACT.

A. Rider ACT provides for an Allowance for Customer-Owned Transformers. More specifically, the Rider provides for a credit of $0.20533 per kW for each kilowatt of monthly billing demand (or the Maximum Kilowatts Delivered (MKD)) to those nonresidential retail customers served at 2,160 volts or higher who furnish, install and maintain any and all transformers and other facilities necessary to reduce the voltage of each entering conductor to the customers' utilization voltage. For a customer such as Argonne National Laboratory, this credit essentially reduces the effective DFC, and is worth approximately $100,000 a year.

Q. WHAT CHANGES DOES THE COMPANY PROPOSE TO RIDER ACT?

A. As spelled out in the testimony of Mr. Alongi and Dr. Jones, ComEd proposes to terminate the payment of the ACT credit for all customers that have received that credit for 30 years, and to offer a voluntary termination of the credit for other customers that own their transformers but have received credits for less than 30 years. The Company proposes to give mandatory termination customers a one-time payment equal to one year's credits based on the average of such credits received for the previous three years. Those customers voluntarily agreeing to end the credits would receive a one-time payment equal to two years worth of credits, also based on the average payment for the previous three years.

Q. WHAT IS YOUR UNDERSTANDING OF THE COMPANY'S OBJECTIVE IN MAKING THIS PROPOSAL?

A. My sense is that the Company merely wishes to standardize these service arrangements for the approximately 225 customers (ComEd Ex. 12.0, p. 23, line 394) that are currently served under Rider ACT.

Q. WHO CURRENTLY OPERATES AND MAINTAINS THESE CUSTOMER-OWNED TRANSFORMERS?

A. My understanding is that the customers currently operate and maintain this equipment. Moreover, if a customer-owned transformer fails I understand that the customer is obligated to replace that equipment if it wishes to continue to receive the ACT credits.

Q. WHAT DO YOU UNDERSTAND WOULD HAPPEN TO THE TRANSFORMERS THAT ARE CURRENTLY OWNED BY CUSTOMERS AFTER THEY CEASE BEING SERVED UNDER RIDER ACT?

A. My understanding is that the customer would continue to own the transformer and that it would continue to provide service. ComEd is not proposing to purchase the transformer. Therefore, the customer would still be responsible for the O&M of the equipment. That customer-owned transformer could continue to service the customer, but the Company would no longer provide the ACT credit. As an alternative, I understand further that the customer could remove the transformer and request standard service of ComEd. For large customers, I understand that ComEd would conduct an engineering study to determine what standard service arrangements would consist of given the particular circumstances of the customer. If the customer wanted something different than standard service, then the customer would pay the difference under Rider NS

Q. PLEASE DESCRIBE THE SITUATION WHERE A CUSTOMER WOULD VOLUNTEER TO TERMINATE THE RIDER ACT CREDIT, WHEN THE TRANSFORMER HAS SEVERAL YEARS OF USEFUL REMAINING LIFE.

A. In that situation, the customer would still own a transformer with useful life and would presumably continue to operate and maintain the equipment, rather than requesting standard service from ComEd. It would be a straightforward comparative life cycle cost evaluation of receiving the ACT credit for the remainder of the 30 year period or taking the 2-year lump sum payment from the Company. However, unless the customer could strike a deal with ComEd to sell the existing transformer, or unless the transformer were being leased from ComEd and that lease could be terminated, I think it would be unlikely that the customer would opt for standard service, since the transformer that was already paid for would have several years of useful life remaining.

Q. WHAT ABOUT CUSTOMERS THAT LEASE THE TRANSFORMER FROM COMED?

A. Currently approximately 98 customers lease their transformers from ComEd and also receive an ACT credit (ComEd response to RDL 3.07). Although affected by the terms of the lease agreement with ComEd, the decision is fairly straightforward for these customers. They merely need to compare the stream of lease charges less the ACT credits, with the cost of standard service plus any required Schedule NS charges less the lump sum payment offered by ComEd, to determine what is in their best interests. I suspect that nothing physical would change since the Company owns the equipment in question.

Q. DOES COMED BENEFIT BY CUSTOMERS OWNING THEIR OWN TRANSFORMERS AND ASSOCIATED EQUIPMENT?

A. Of course. By the customer providing its own transformation equipment, the Company saves the capital costs associated with the equipment plus the cost of operating and maintaining that equipment. In the case of a large customer like Argonne National Laboratory, which has eight 138 kV/13 kV transformers, that cost avoidance will be significant. For example, if the installed cost of the transformers and associated equipment were $5 million, and the annual rental rate, including O&M, insurance and other loads were approximately 18 percent a year, then the Company's savings would be approximately $900,000 a year if the Company would have to install the same or similar transformation equipment. For that savings, the Company would pay Argonne approximately $100,000 a year under the existing Rider ACT. The installed cost of the required transformation equipment would have to fall to $555,000 for ComEd's savings to fall to zero. It is highly unlikely that ComEd would be able to provide standard transformation service to Argonne for an investment of $555,000. This comparison would suggest that, if anything, the Rider ACT credit should be increased rather than eliminated.

Q. MR. ALONGI AND DR. JONES STATE AT LINES 378 THROUGH 381 OF THEIR TESTIMONY THAT THE USEFUL LIFE OF TRANSFORMERS IS ABOUT 30 YEARS, AND THAT THE EXTENSION OF CREDITS NEED NOT EXTEND BEYOND THE TRANSFORMER'S USEFUL LIFE. DO YOU AGREE?

Q. No. The customer has taken on the responsibility of providing the necessary step down transformation in order to receive the credit. There was no specified limit on the number of years for which the credit would be given. Moreover, the average useful life of a transformer is irrelevant. If a piece of equipment is kept in excellent condition and provides useful service for 40 or 50 years, ComEd continues to realize the savings. Argonne National Laboratory has probably received the credit for 30 years since it has some transformers that are approximately 40 years old. However, its largest four transformers were installed between 15 and 18 years ago, and so have several years of useful life remaining. Moreover, I know for a fact that Argonne staff fully expect to have to replace its transformers at the government's expense if and when they fail. Thus, the saving to ComEd will essentially be realized in perpetuity. I would note that there is no termination of Rider NS charges when the useful life of any special equipment that it provides reaches its average useful life. Indeed, Rider NS states explicitly that special facilities will be furnished, "...provided that the Company is allowed to recover from the retail customer the costs of furnishing, installing, owning, operating, **replacing**, and maintaining such services or facilities (emphasis added)." The same concept should be applied to Rider ACT credits.

Q. ARE THERE CUSTOMERS THAT LEASE TRANSFORMERS FROM COMED WHICH MIGHT BE ABLE TO SAVE MONEY UNDER THE COMPANY'S PROPOSAL?

A. According to the Company's response to IIEC Request 2.88, that is apparently the case. It is stated there that, "...there are 83 customers that own some of the transformers at their premises and rent others from ComEd. For many, if not all of those customers, the reduction in Rider NS rental charges would exceed the Rider 8 [ACT] credit that they currently receive resulting in savings, all other things being equal."

Q. GIVEN THAT SOME CUSTOMERS MIGHT BE ABLE TO SAVE MONEY UNDER THE COMPANY'S PROPOSAL, IS THERE AN ADJUSTMENT TO RIDER ACT THAT YOU CAN SUPPORT?

A. Yes. The only objection I have to the Company's proposal is the mandatory aspect for customers that have been receiving the credit for 30 years. As I noted above, the 30 year average useful life of transformers is irrelevant to whether the Company will realize savings or whether that credit should be continued. I can support the voluntary aspect of the Company's proposal. If every customer, regardless of how long it has been receiving the credit, were to be given an incentive to terminate its Rider ACT service, then each customer could undertake its own comparative life cycle cost analysis to determine what is in its best interests. That could be done in conjunction with discussions with the Company regarding what would be the cost under standard service plus possible Rider NS charges, so that the customer could make a rational choice. This strikes me as a reasonable and equitable way to mutually terminate what would seem to be essentially a long term, ongoing, mutually beneficial arrangement between the customer and ComEd. I would also note that, if the response to ComEd's offered incentive payments leads to an insufficient number of customers terminating their Rider ACT service in the Company's view, then ComEd need only raise the amount of the incentive payments to solicit the response that it desires for whatever administrative or other cost saving reasons it may have.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

DALE E. SWAN

Dr. Swan is a senior economist and principal at Exeter Associates, Inc. His areas of expertise include energy supply and demand analysis, electric industry restructuring, utility cost allocation and rate structure design, utility contract negotiation, antitrust policy, and public utility regulation.

Dr. Swan has presented expert testimony in utility rate cases before the Federal Energy Regulatory Commission and before numerous state regulatory commissions. He has testified on marginal and embedded costing, rate structure design, long-term demand forecasting, short-term sales forecasts, the treatment of off-system sales, electric industry restructuring, and antitrust considerations. He has directed major projects for the U.S. Department of Energy, the U.S. Air Force, and the Rhode Island Public Utilities Commission on such issues as alternative power supply options and innovative rate structure experiments and implementation, and he has prepared and presented seminars and workshops on such issues as marginal costing, rate design, and interruptible rates for, among others, the National Regulatory Research Institute, the U.S. Department of Energy, and for state commission staffs in Maryland, Minnesota, and New Hampshire.

Dr. Swan has assisted federal agencies in the negotiation of electric power supply contracts and in the financial and locational assessment of transmission and generation projects. He has also prepared reports to several federal and state agencies on costing methods, rate design, the demand for electric power, PURPA requirements, bulk power supply planning, stranded cost recovery, standby rates, value-of-service pricing, the use of special contracts, and other issues. He has also acted as an Advisor to the Maine Public Utilities Commission in the restructuring proceedings for the three investor-owned Maine electric companies.

<u>Education</u>:

B.S. (Business Administration) - Ithaca College, 1962.

M.A. Program in Economics - Tufts University, 1962-63.

Ph.D. (Economics) - University of North Carolina at Chapel Hill, 1972.

<u>Previous Employment</u>:

1976-1980	-	Senior Economist, J.W. Wilson & Associates, Inc.
1974-1976	-	Associate Professor of Economics, Jacksonville State University
1974	-	Economist, Office of Energy Systems, Federal Energy Administration
1973	-	Staff Economist, Economics Department, Arabian-American Oil Company

1968-1973	-	Assistant and Associate Professor of Economics, Hampden-Sydney College
1969-1973	-	Visiting Assistant Professor of Economics, Randolph-Macon Womans College
1967-1968	-	Assistant Professor of Economics, Southern Methodist University
1966-1967	-	Visiting Assistant Professor of Economics, North Carolina Central University
1963-1964	-	Market Research Analyst, The Carter's Ink Company

Previous Professional Work:

At J.W. Wilson & Associates, Inc., Dr. Swan had primary responsibility for the development and direction of several of the firm's largest projects relating to the electric utility industry and costing and rate design issues in particular. Dr. Swan also had major responsibilities in the areas of cogeneration, antitrust, PURPA requirements, and technical assistance to state regulatory authorities under DOE grant programs.

At the Federal Energy Administration, Dr. Swan participated in the development of a National Energy Accounting System, similar to and compatible with the National Income and Product Accounts and the U.S. Input/Output Accounts. During his tenure at Jacksonville State University, Dr. Swan continued with this work as a consultant to the FEA.

While with ARAMCO, Dr. Swan prepared financial analyses of capital investment alternatives, developed cost trend estimates for price negotiations, and initiated the preparation of revised price trend factors to be used for budgeting purposes.

At Carter's Ink Company, Dr. Swan was responsible for conducting new product and new market research for the Director of Marketing, including consumer attitudinal studies on new product and packaging designs.

Dr. Swan has taught both graduate and undergraduate courses during his academic career. Among the courses he has taught are Microeconomic Theory, Industrial Organization, Economic History, International Trade, Economic Development, and Principles of Economics.

Selected Publications, Papers, and Reports:

"Fermi National Accelerator Laboratory Phase 1 Electric Supply Options Study," (Exeter Associates, Inc., for the U.S. Department of Energy, Federal Energy Management Program, December 2004.)

"Phase 1 Electric Power Options Study for Brookhaven National Laboratory," (Exeter Associates, Inc. for the U.S. Department of Energy, Federal Energy Management Program, June 2004).

"Phase 1 Electric Supply Options Study for Fermi National Accelerator Laboratory," (Exeter Associates, Inc. for the U.S. Department of Energy, Federal Energy Management Program, December 2004).

"Electric Power and Natural Gas Supply Options Study for the DOE Oak Ridge Reservation," (Exeter Associates, Inc., for the U.S. Department of Energy, Federal Energy Management Program, March 2004).

"A Comparative Evaluation of Two Proposals to Meet the Long-Term Steam Requirements of the Savannah River Site." (Exeter Associates, Inc., for the U.S. Department of Energy, Federal Energy Management Program, November 2001.)

"Electric Power Supply Options to Meet the Cold Standby and Possible Restart Requirements of the Portsmouth Gaseous Diffusion Plant." (Exeter Associates, Inc. for the U.S. Department of Energy, Federal Energy Management Program, October 2001.)

"Strategic Options in Planning for the Long-Term Power Requirements of the DOE/OAK Laboratories." (Exeter Associates, Inc. for the U.S. Department of Energy, Office of Project and Fixed Asset Management, September 1998.)

"Utility Options Study: Rocky Flats Environmental Technology Site." (Exeter Associates, Inc. for the U.S. Department of Energy, Office of Project and Fixed Asset Management, March 1997.)

"Competitive Acquisition of Power by Federal Agencies: Current Possibilities and Future Prospects." (Presented before the Competitive Power Congress, Philadelphia, Pennsylvania, July 21, 1995.)

"Standby Rate Rulemaking: A Discussion of Issues and Proposed Positions." (Exeter Associates, Inc. for the Maine Public Utilities Commission, January 10, 1995.)

"Stranded Cost Rulemaking: A Discussion of Issues and Proposed Positions." (Exeter Associates, Inc. for the Maine Public Utilities Commission, January 3, 1995.)

"Superconducting Super Collider Permanent Power Supply: A Preliminary Consideration of Supply Alternatives." (Exeter Associates, Inc., revised draft report prepared for the U.S.

Department of Energy, Office of Organization, Resources and Facilities Management, March 1992.)

"The Potential Savings Associated with Exporting EBR-II Energy from the Idaho National Engineering Laboratory to Another Federal Facility." (Exeter Associates, Inc. for the U.S. Department of Energy, Office of Project and Facilities Management, March 1991.)

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“An Evaluation of the Financial Benefits to the United States Government from Using $175 Million of the TRNLC Fund to Purchase Generating Capacity to Reduce Power Costs of the Superconducting Super Collider.” (Exeter Associates, Inc. for the U.S. Department of Energy, Office of Project and Facilities Management, January 1990.)

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"Electric Power Supply Options for the Continuous Electron Beam Accelerator Facility." (Exeter Associates, Inc. for the U.S. Department of Energy, Office of Project and Facilities Management, July 1989.)

"The Potential Future Value of Byproduct Steam from a New Production Reactor Based on Four Alternative Technologies and Three Alternative Sites," with Steven Estomin and Richard Galligan. (Exeter Associates, Inc. for the U.S. Department of Energy, August 1988.)

"An Analysis of the Optimal Allocation of Available Western Area Power Administrative Preference Power Among Three Northern California Laboratories," with Charles E. Johnson. (Exeter Associates Inc. for DOE San Francisco Operations Office, March 1986.)

"Report on the Role of Special Contracts in Electric and Gas Utility Ratemaking." (Exeter Associates, Inc. for the U.S. Postal Service, February 1984.)

"The Electric Utility Industry," in <u>Study of Pricing Precedents in the Public Utility Industry</u>. (Exeter Associates, Inc., for the U.S. Postal Service, February 1984.)

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"A Summary and Analysis of Federal Legislation Affecting Electric and Gas Utility Diversification." (Exeter Associates, Inc. for Argonne National Laboratory, August 1981.)

"Average Embedded Cost Studies as the Basis for Rate Designs Consistent with the Goals of the Public Utility Regulatory Policies Act of 1978," prepared for ORI, Inc. and the DOE Office of Utility Systems, February 6, 1981.

"Analysis of the Major Comments Made on the ERA Proposed Voluntary Guideline for the Cost-of-Service Standard Under the Public Utility Regulatory Policies Act of 1978," prepared for ORI, Inc. and the DOE Office of Utility Systems, February 1981.

"The Rhode Island - DOE Electric Utilities Demonstration Project." Final Report - November 1980, and three Interim Reports in July 1978, November 1979, and July 1980. (J.W. Wilson & Associates, Inc. for the Rhode Island Division of Public Utilities and Carriers.)

"An Evaluation of Power Supply Planning by the Six Investor-Owned Electric Utilities in South Dakota," with Ralph E. Miller. (J.W. Wilson & Associates, Inc. for the South Dakota Public Utilities Commission, 1977.)

<u>The Structure and Profitability of the Antebellum Rice Industry: 1859</u>. (New York: Arno Press, 1975.)

"The Structure and Profitability of the Antebellum Rice Industry: 1859." <u>Journal of Economic History</u>, (December 1972.)

"The Productivity and Profitability of Antebellum Slave Labor: A Micro Approach," with James D. Foust. <u>Agricultural History</u>, (January 1970). Later published in William N. Parker (ed.), <u>The Structure of the Cotton Economy of the Antebellum South</u>. (New York: Agriculture History Society, 1970.)

<u>Participation in Conferences, Seminars and Workshops</u>:

Competitive Power Congress, 1995.

Department of Energy Utility Conferences, 1985, 1986, 1990, 1992, 1995, 1996, 1997.

DOD/DOE Combined Utility Planning Conference, March 1987.

American Historical Association Meetings, 1981.

National Regulatory Research Institute Workshop on Time-of-Use Rates, September 1979.

National Regulatory Research Institute State Needs Assessment Conference, August 1979.

Southern Economic Association Meetings, 1969, 1972, 1975.

Economic History Association Meetings, 1972.

Expert Testimony

Presented by Dale E. Swan

1. Before the Public Utilities Commission of the State of Ohio, Case No. 78-676-EL-AIR, on marginal costs and electric rate structure design.

2. Before the Public Utilities Commission of the State of South Dakota, Docket No. 3362, on marginal costs and electric rate structure design.

3. Before the Public Utilities Commission of the State of South Dakota, Docket Nos. F-3240 and F-3241, on electric rate structure design.

4. Before the Public Utilities Commission of the State of Rhode Island, Docket No. 1311, on the design of a proposed inverted rate structure experiment.

5. Before the Public Utilities Commission of the State of Rhode Island, Docket No. 1262, on the operation and the results of a time-of-day rate experiment.

6. Before the Public Utilities Commission of the State of South Dakota, Docket No. F-3116, on test year sales forecasts.

7. Before the Public Utilities Commission of the State of Montana, Docket No. 6441, on test year sales forecasts.

8. Before the Public Service Commission of the State of Maryland, Case No. 6807, on long-term demand forecasting methodology.

9. Before the Public Service Commission of the State of New York, Docket No. 27136, on test year sales forecasts and economic impact.

10. Before the Federal Energy Regulatory Commission, Docket No. ER77-530, on retail competition in the Ohio electric power market.

11. Before the Public Service Commission of the State of Maryland, Case No. 7441 (Phase III), on electric rate structure design and PURPA ratemaking standards.

12. Before the Public Utilities Commission of the State of Rhode Island, Docket No. 1591, on class revenue requirements and electric rate structure design.

13. Before the Public Utilities Commission of the State of Rhode Island, Docket No. 1606, on PURPA Section 111 standards, class cost-of-service, and rate structure design.

14. Before the Public Utilities Commission of the State of Rhode Island, Docket No. 1605, on class revenue requirements and electric rate structure design.

15. Before the Public Utilities Commission of the State of Idaho, Case No. U-1006-185, on class revenue requirements and rate design.

16. Before the Illinois Commerce Commission, Docket No. 82-0026, on marginal-cost-based class revenue responsibilities and rate design.

17. Before the Public Utilities Commission of the State of Idaho, Case No.. U-1009-120, on contractual arrangements, embedded-cost-based class revenue requirements, and rate design.

18. Before the Public Utilities Commission of the State of Maryland, Case No. 7695, on proper electric class cost-of-service methodologies.

19. Before the Public Service Commission of Nevada, Docket No. 83-707, on marginal-cost-based class revenue responsibilities and rate design.

20. Before the Illinois Commerce Commission, Docket No. 83-0537, on marginal-cost-based class revenue responsibilities, rate design, and rate schedule qualification standards.

21. Before the Public Utilities Commission of the State of Idaho, Case No. U-1009-137, on jurisdictional separations, embedded class cost-of-service studies, interruptible service credits, and class revenue requirements.

22. Before the South Carolina Public Service Commission, Docket No. 84-122-E, on embedded class cost-of-service methodologies, class revenue requirements, and rate design.

23. Before the Public Utilities Commission of the State of Idaho, Case No. U-1500-157 (May 1985), on the public interest aspects of declaring one utility as the sole supplier of the Idaho National Engineering Laboratory.

24. Before the Illinois Commerce Commission, Docket Nos. 83-0537 (Step 2) and 84-0555 (Consolidated), June 1985, on marginal-cost-based class revenue responsibilities and rate design.

25. Before the Public Utilities Commission of the State of Idaho. Case No. U-1006-265A (May 1987), on embedded class cost-of-service studies, class revenue requirements, and rate design.

26. Before the Public Utilities Commission of the State of Maine, Docket No. 86-242 (August 1987), on by-pass and incentive rate discounts for large industrial customers.
27. Before the Illinois Commerce Commission, Docket No. 87-0427, (February and April 1988), on marginal-cost-based class revenues, Ramsey pricing considerations, and industrial rate design.

28. Before the Illinois Commerce Commission, Docket No. 87-0695, (April 1988), on marginal-cost-based class revenues, Ramsey pricing issues, and industrial rate design.

29. Before the Indiana Utility Regulatory Commission, Cause No. 37414-S2 (October 1989), on ratemaking treatment of off-system sales, embedded cost-of-service study, and rate design.

30. Before the Public Utilities Commission of the State of Maine, Docket 89-68 (January 1990), on measurement and use of marginal costs for determining class revenues.

31. Before the Federal Energy Regulatory Commission, Docket No. EC90-10-000, et. al. (May 1990), with Matthew I. Kahal, on the potential effects of the Northeast Utilities acquisition of Public Service New Hampshire on market concentration and competition in the New England bulk power market.

32. Before the Illinois Commerce Commission, Docket No. 90-0169 (August and October 1990), on the estimation of marginal costs, class revenue responsibilities, and industrial rate design.

33. Before the Public Service Commission of Nevada, Docket Nos. 91-5032 and 91-5055 (September 1991), on the estimation of marginal costs, class revenue responsibilities and rate design for large power users.

34. Before the Public Service Commission of Nevada, Docket No. 92-1067 (May 1992), on the estimation of marginal costs, the cost of providing interruptible power, class revenue responsibilities, and rate design for large power users.

35. Before the Public Utilities Commission of the State of Maine, Docket No. 92-095 (February 1993), Affidavit regarding the efficacy of rate discounts in attracting new business.

36. Before the Public Utilities Commission of the State of Maine, Docket No. 92-315 (June 1993), on revamping of the rate structure to meet competition for sales.

37. Before the Public Utilities Commission of the State of Maine, Docket No. 92-345 (August 1993), with Marvin H. Kahn, on price cap mechanisms as an alternative form of regulation.

38. Before the Public Service Commission of Nevada, Docket No. 92-9055 (October 1993), on franchise rights to serve a large DOE customer.

39. Before the Illinois Commerce Commission, Docket No. 94-0065 (June 1994), on the estimation of marginal costs, class revenue responsibilities, and industrial rate design.

40. Before the Public Service Commission of Nevada, Docket No. 93-11045 (June 1994) on the estimation of marginal costs, environmental externality adders, competition for loads, and class revenue responsibilities.

41. Before the Idaho Public Utilities Commission, Case No. IPC-E-94-5 (November 1994), on embedded class cost allocation and class revenue responsibilities.

42. Before the Public Utilities Commission of the State of Maine, Docket No. 92-315 (II) (March 1995), on the estimation of marginal distribution demand and customer costs.

43. Before the Public Utilities Commission of the State of Maine, Docket No. 95-052 (RD) (October 1995 and January 1996), with Daphne Pscharopoulos, on the estimation of marginal costs as the basis for class revenues and rate design.

44. Before the Public Service Commission of Nevada, Docket No. 96-7020 (November 1996), on the estimation of marginal costs, class revenue responsibilities, and the reasonableness of fixed, up-front facilities charges.

45. Before the Public Service Commission of Montana, Docket No. 97.7.90 (November 1997 and March 1998), on aspects of Montana Power Company's proposed restructuring plan.

46. Before the Illinois Commerce Commission, Docket No. 99-0117 (April 1999), on the design of distribution delivery rates for Commonwealth Edison Company.

47. Before the Public Utilities Commission of Nevada, Docket Nos. 99-4005 and 99-4006, (November 1999), on the design of an electric distribution service tariff for Nevada Power Company.

48. Before the Public Utilities Commission of Nevada, Docket No. 99-7035 (January and February 2000), on Nevada Power proposed revision to its base rates and deferred energy adjustment rates, including the recovery and allocation of deferred capacity costs and the appropriate calculation of annualized fuel and purchased power costs.

49. Before the Illinois Commerce Commission, Docket No. 01-0423 (August, October 2001), on the proper design of distribution delivery rates for Commonwealth Edison Company.

50. Before the Public Utilities Commission of the State of Maine, Docket No. 2001-239 (November 2001), on appropriate procedures governing the provision of rate discounts to retain or attract customers.

51. Before the Public Utilities Commission of Nevada, Docket Nos. 01-10001, 01-10002 and 01-11029 (February 2002), on Nevada Power Company's proposed class cost allocations and revisions to its base rates.

52. Before the Illinois Commerce Commission, Docket No. 02-0479 (August 2002), on the appropriateness of the Company's petition to have bundled Rate 6L service to customers with loads of 3 MW or more declared a competitive service, thereby eliminating Rate 6L as a service of last resort for these customers.

53. Before the Illinois Commerce Commission, Docket Nos. 02-0656, 02-0671, and 02-0672 (CONS.) (December 2002), on proposed changes to Commonwealth Edison Company's retail access options.

54. Before the Public Utilities Commission of Nevada, Docket Nos. 03-10001 and 03-10002 (January 2004), on Nevada Power Company's proposed class revenue allocation and the imposition of new Customer Specific Facilities Charges on certain large customers.

55. Before the Illinois Commerce Commission, Docket No. 05-0159 (June 2005), on the need for Commonwealth Edison Company to offer a fixed-price POLR service to large customers.

56. Before the Illinois Commerce Commission, Docket No. 05-0597 (February 2006), on the allocation of costs and the design of rates for retail delivery service.

DOE Exhibit 1.1

CERTIFICATE OF SERVICE

I, Arthur Perry Bruder, attorney for the United States Department of Energy, hereby certify that, on Monday, February 11, 2008, in order to meet the service requirements in Illinois Commerce Commission proceeding No. 07-0556, which concerns the rates of Commonwealth Edison Company, I:

(1) placed the Testimony and Exhibits of Dr. Dale E. Swan on the Illinois Commerce Commission's E-Docket, in accordance with the applicable procedures;

(2) served the Testimony and Exhibits of Dr. Dale E. Swan via email on both of the Administrative Law Judges and on the entire service list.

Arthur Bruder
February 11, 2008

Delivery Service Rate Case

Docket No. 07-0566

High Voltage Delivery Class
Customers Up To 10 MW
Allocation Factors

Line Nos.	Allocation Factors	ICC Total	Total Class	69 kV And Above	Below 69 kV
1	**Energy Delivered to HV Class At Distribution Level**	91,061,817	384,419	203,369	181,050
2	**Percent of ICC Total**		0.42%	0.22%	0.20%
3	**Coincident Peak Demand - ALL**	21,686,584	50,587	28,651	21,936
4	**Percent of ICC Total**		0.23%	0.13%	0.10%
5	**Coincident Peak - Below 69 kV**	21,159,191	21,936	-	21,936
6	**Percent of ICC Total**		0.10%	0.00%	0.10%
7	**Non-Coincident Peak Demand Below 69kV**	23,460,965	45,377	-	45,377
8	**Percent of ICC Total**			0.00%	0.19%

Source: ComEd Response to IIEC 1.02 Supp_Attach1
ComEd Response to DOE 1.17_Attach 1